Gas Pipeline Group

June 26, 2000

Dockets Facility, U. S. Department of Transportation, Room PL-401
400 Seventh Street, SW
Washington, DC 20590-0001

RE: [Docket No. RSPA-99-6355; Notice 3]
Pipeline Safety: Pipeline Integrity Management in High Consequence Areas

The Enron Gas Pipeline Group (GPG), which includes Houston Pipe Line Company, Florida Gas Transmission Company, Northern Plains Natural Gas Company, Northern Natural Gas Company, and Transwestern Pipeline Company, operates over 26,000 miles of natural gas transmission pipelines that are subject to the pipeline safety regulations. GPG has a strong commitment to pipeline safety, and as such has an interest in any rulemaking that impacts pipeline safety. Further, GPG supports the principle of providing a high level of assurance of pipeline integrity in high consequence areas. Accordingly, GPG wishes to submit comments on the subject Docket. In addition to the comments offered below, GPG also supports the comments submitted by the Interstate Natural Gas Association of America (INGAA), of which GPG is an active member.

This Notice of Proposed Rulemaking (NPRM) does not directly impact the GPG facilities noted above. GPG believes that the prescriptive approach proposed herein for hazardous liquids pipelines may set an inappropriate precedent for the pending rulemaking addressing the integrity of natural gas transmission pipelines. GPG agrees with the Office of Pipeline Safety (OPS) that the expanded use of risk management practices can result in a more effective utilization of industry resources for improving pipeline safety. GPG also agrees that improving public awareness of both the location of pipeline facilities as well as the precautions to employ when working near these facilities will assist the pipeline operators in reducing potential third party damage. GPG is, however, concerned with the approach used to implement the risk assessment practices espoused in this NPRM for the following reasons:

- This rulemaking does not adequately address the major cause of pipeline accidents—third party damage. GPG strongly recommends that this rulemaking encourage stricter enforcement of existing One-Call legislation as the most effective means for improving pipeline safety.
- This proposal with its prescriptive inspection and testing approach will force pipeline operators who have well maintained, reliable systems to expend resources unnecessarily.
- The heavy oversight requirements proposed by the Office of Pipeline Safety (OPS) in the preamble of this rulemaking may undermine the current cooperative relationship between OPS and the pipeline industry for continuing improvement in pipeline safety.

- This prescriptive approach will ultimately limit the available resources for improvements in potential problem areas that the operator has identified on his own and therefore divert resources from higher priority activities thus adversely affecting pipeline safety.
- This NPRM places a much higher confidence level in the capability of magnetic flux leakage detection devices (smart pigs) than is warranted based upon the current technology limits. This is especially true for the detection of gouges and grooves for which the technology is still being developed.
- This NPRM is devoid of any cost benefit analysis result that would justify the proposed inspection and testing schedule requirements. An independent review of DOT reportable incidents for the past thirteen years recently published by the Gas Research Institute (GRI) provides substantive evidence that only about 2 percent of all gas and liquid pipeline incidents due to third party damage could have been prevented by current in-line inspection techniques.

The following comments further address the problematic issues noted above along with a number of others. Most of these comments address statements and positions expressed by OPS and others in the "Supplementary Information" or preamble of the NPRM. The following discussion addresses each of these issues in the order that they appear in the preamble of this NPRM.

Statutory Requirements
"49 U.S.C. 60102(F)(2)—OPS is to prescribe *(if necessary)* additional standards requiring the periodic inspection of pipelines in USAs and high-density population areas. The regulations are to prescribe when an instrumented internal inspection device, or similarly effective inspection method, should be used to inspect the pipeline."

OPS has cited 49 U.S.C. 60102(f)(2) as having provided the directive for this prescriptive inspection program. This referenced directive by Congress also included the qualification "if necessary", as indicated parenthetically above, regarding the necessity for regulations that are to prescribe when an instrumented internal inspection device, or similarly effective inspection method, should be used to inspect a pipeline. The necessity or justification for mandatory smart pigging or pressure testing on a prescribed schedule has not been demonstrated in this NPRM. There are several serious pipeline incidents identified in the "Accident Analysis" section that can only be presumed to be the basis for this prescriptive inspection program. But as that commentary notes, the causes for each incident were complex and the need or benefit of a prescriptive inspection program is not developed in this discussion. Lacking this justification it is not clear why such a highly prescriptive pressure testing or intelligent pigging program is warranted based upon the operating history of the majority of well-maintained pipeline facilities. And even more disturbing is the requirement to expend industry resources for repeated testing of a pipeline facility even after it has been determined to be in sound operating condition. GPG reiterates its agreement with the principles of integrity assessment and assurance in high consequence areas, but does not agree that the prescriptive approach specified herein is the most effective way to achieve this objective.

Comments Received in the Docket

Specification vs. Performance

"The proposed rule uses both performance and specification-based language…..OPS needs to create incentives for operators to invest in the development of new technology."

This comment section states that the proposed rule uses both performance and specification-based language. GPG supports the performance-based portion of this proposed regulation in that it encourages the pipeline industry to develop new technologies for the inspection and repair of pipelines. The prescriptive inspection schedule proposed, however, does not allow for any risk based analysis on the part of the operator to determine when and to what extent an inspection program is necessary based upon such factors as the actual operating history of a pipeline facility. This activity should be a performance-based requirement as well.

If OPS is to create an incentive for pipeline operators to invest in the development of new technology, it must provide pipeline operators the opportunity to utilize both new and existing technology to assess and mitigate risks. The operators should also be allowed to use this assessment to determine an effective and appropriate schedule.

Emergency Flow Restricting Devices (EFRDs)

Previously published and referenced reports show that these devices would provide little or no safety benefit for natural gas transmission pipelines. Due to the different operating characteristics of liquid and gas transmission pipelines and the differences in the products transported, a definitive correlation as to any potential benefits is difficult to make.

Integrity Assessment Tools

"At least two types of tools should be used: (1) Geometry pigs for detecting changes in circumference and (2) magnetic flux leakage pigs for determining wall anomalies, or wall loss due to corrosion……OPS is concerned about improving the technology capability to detect gouges and dents……Research and development continues for reliable identification of other types of seam defects, such as hook cracks. With the use of ultrasonic and MFL (transverse orientation) technology, pipeline segments that have experienced fatigue cracking can now be inspected. Cracks with a potential to rupture can be identified and repaired prior to growing to a critical stage…..Defects might exist as a result of the manufacturing process or damage to the pipe during shipping or even construction…..An operator must test to a minimum of 1.25 times maximum operating pressure because research has shown that at that level of pressure all critical defects can be identified and eliminated."

In the discussion of the Current Capabilities of Internal Inspection Devices the potential use of ultrasonic detection tools is not mentioned as a preferred technology but is rather discussed only briefly in a later portion of this section. This technology has capabilities in the crack detection problem area comparable to that of the magnetic flux leakage pigs. Crack detection is very difficult to perform effectively with an in-line inspection tool using either technology. Inspections can result in numerous, expensive "false calls" or indications of anomalies that do not actually exist and conversely may fail to locate cracks that do exist. It is noted that crack growth is a critical problem due to pressure cycling and it needs to be pointed out that pressure testing of a pipeline can also initiate crack growth. Although it is noted that pressure testing will eliminate critical defects, including cracks, the pressure test can also cause small cracks to form or grow. Under some conditions or testing scenarios these new or enlarged cracks can increase the risk of failure during continued operation of the pipeline. It is also mentioned that pressure testing will remove defects that might exist as a result of the manufacturing process or damage to the pipe during shipping or even construction. The proof testing of the pipeline during its original construction and testing will eliminate these defects. Therefore, repeating this testing at a later date is redundant and unnecessary for this stated purpose.

Testing and inspection methods, including smart pigging and pressure testing, should be used judiciously. The tests and inspections must be selected based on goals, and must be properly designed and executed to accomplish those goals so as to not cause additional concerns or exacerbate otherwise innocuous conditions.

Communications

"OPS invites comments on how local officials could use and benefit from risk assessment information, how the consequences of potential failures should be characterized, how risk control actions should be described and what performance indicators would be meaningful."

GPG agrees that improved communications with various stakeholders is beneficial for both the prevention of pipeline accidents, and on those rare occasions where it is necessary, the response to pipeline accidents. We would question the benefit, however, of sharing risk assessment information other than the type of data used in the analysis and possibly a brief summary of the type of results obtained. As noted in another section of this NPRM there is a highly skilled qualification level required to perform the risk assessment process. There is a wide variety of information that is analyzed and the assessment results require some level of skill and experience in interpretation in order to be meaningful. The assessment results for each individual pipeline facility must be reviewed in comparison to the assessment results for all of the similar facilities of that operator so that an effective mitigation program, if necessary, can be carried out to provide the maximum benefit. Possible bias on the part of local officials could adversely impact the overall program of a pipeline operator by forcing the operator to address insignificant issues in one location at the expense of potentially more serious issues at another.

API Standard on Pipeline Integrity

This standard was developed specifically for hazardous liquid pipelines and, as such, cannot be directly applied to natural gas transmission pipelines. A companion standard for the latter is to be developed.

The Proposed Rule
Which Operators Are Covered?

GPG understands that follow-on NPRMs are planned for operators with fewer than 500 miles of liquid pipelines, as well as for gas pipeline operators. GPG trusts that in the development of regulations for smaller operators the level of safety or integrity expected will not be function of system mileage.

What Must Be in the Baseline Assessment Plan?

Current internal inspection tools have a limited capability of detecting deformation anomalies including dents, gouges and grooves. The limits for this detection capability need to be defined or pipeline operators will have an unending search for anomalies that are beyond the current technology's capabilities, and may well have no impact on pipeline integrity.

When Must the Baseline Assessment Be Completed?

In regard as to whether seven years is an adequately protective minimum period to complete the baseline assessment of all of the pipelines impacted by this NPRM, it is expected that the responses will be based upon the bias of the responder. There are simply limits both physically and financially to the timing for this large a task. One of the pipeline industry concerns is the availability of inspection equipment and manpower to handle this volume of intelligent pigging activity in this limited period of time. Such a requirement could result in a huge demand for this service in a short period of time, taxing the industry's capabilities. If a time limit is to be established for this assessment, a better idea of how many pipeline miles will need to be inspected should be determined and the capacity of the intelligent pigging industry to handle this mileage should be established.

What Are the Elements of an Integrity Management Program?

Item number (6) "methods to measure the program's effectiveness," is a problematic issue. Due to the rarity of pipeline incidents any determination of a change in a pipeline's relative risk on a short-term basis is impossible to measure. This is one reason that the pipeline industry has utilized the risk assessment program as just one of their analytical tools in the evaluation of pipeline systems. The effectiveness of a relative risk evaluation will not be evident for many years. This measurement issue has provided similar challenges with the current OPS Risk Management Demonstration programs since it is difficult to quantify an incremental change in safety for an industry that has relatively few accidents.

What Remedial Action Must be Taken?
"We invite comments on whether the rule should contain specific time lines for conducting repairs."

The repair requirements are best left to the pipeline operator to evaluate and execute. The pipeline operator has a tremendous vested interest in properly maintaining his pipeline facilities both from a public safety standpoint and from an economic standpoint. From simply an economic standpoint, it is in the best interests of pipeline operators to conduct appropriate repairs in a timely manner. Any prescriptive time lines would also involve the difficult problem of trying to define what type anomalies require repair in what type of circumstances.

Preventive and Mitigative Measures To Protect the High Consequence Area

One of the recommendations for improving the response to pipeline accidents is to conduct drills with local emergency responders. This is a practice that GPG already performs and it has proven to be quite effective. One of the challenges of this type of program is that it requires significant time and resources on the part of the pipeline operator and the emergency responders to perform this activity properly. In addition, by their nature, transmission pipelines cross large geographic areas potentially impacting a very large number of responders. Effectively training all of these responders is a daunting task. GPG would suggest that this type of activity be focused on those areas that have the greatest risk of impact on the public and environment.

What Is a Continual Evaluation of a Pipeline's Integrity?

Comment is invited in the NPRM on the minimum period for integrity assessments. After the initial assessment is completed, and assuming that it can be effectively and economically performed in the prescribed seven years, there must be some discretion allowed on the part of the pipeline operator to determine an appropriate evaluation interval. The operator has the greatest knowledge regarding the condition of the pipeline facility, the risk factors associated with its operation, and the impact of potential pipeline failures. Since the initial evaluation will have already confirmed that the pipeline facility is in satisfactory condition or identified the repairs, if any, that are required it would certainly be an unwise use of resources to turn around and conduct another assessment when the risk of damage to the pipeline is low. This evaluation is one of the benefits of a risk assessment program—determining which pipeline facilities justify attention and which facilities should continue to perform safely without unnecessarily expending valuable resources. The safe operating history of the vast majority of pipeline facilities attests to the fact that a prescriptive assessment schedule isn't necessary.

Methods To Measure the Program's Effectiveness

"Again, the proposal is performance-based to encourage the operator to choose the most effective risk control measures."

A method to measure the program's effectiveness is the same problematic issue that was addressed earlier in these comments. Even though OPS has included this measurement of effectiveness as a required element of the proposed rule, there is no guidance offered on the means to perform this task. As stated earlier, it will be very difficult to measure the improvement in performance over a short time period for an industry that has the safety record of the pipeline industry. The success of an integrity management program is basically going to either be "pass" or "fail". If no accidents have occurred, the program is successful and conversely the program will be deemed a failure if an accident should happen, even though the accident may or may not be due to a deficiency in the program.

Regulatory Analyses and Notices
"The Department of Transportation (DOT) does not consider this action to be a significant regulatory action under section 3(f) of Executive Order 12866 (58 FR 51735; October 4, 1993)….This proposed rule is not significant under DOT's regulatory policies and procedures (44 FR 11034; February 26, 1979)…..The cost of developing the necessary program is estimated to cost the industry $1.5 million with an additional annual cost of $66,000….OPS requests information from the public on how many operators are likely to install EFRD's and their potential benefit…..The benefits to this proposal can not be easily quantified but can be described in qualitative terms…..Requiring operators to use the integrity management process, and having regulators validate the adequacy and implementation of this process, should expedite the operators' rates of remedial action, thereby strengthening the pipeline system and reducing the public's exposure to risk…..OPS has not provided quantitative benefits for the continual integrity management evaluation required in this proposed rule…..OPS believes the added security this assessment will provide and the generally expedited rate of strengthening the pipeline system in populated and important environmental areas and commercially navigable waterways, is benefit enough to promulgate these proposed requirements……Additionally, all 66 operators will be required to update their plans annually. This will take approximately 33 hours per plan."

It is hard to imagine how the Department of Transportation (DOT) considers this rulemaking as an insignificant regulatory action. Prescribing that pipeline operators spend tens or hundreds of millions of dollars for pipeline inspections, assessments and testing is definitely significant. Based upon GPG's experience with the risk assessment process, OPS has significantly underestimated the costs for both developing the assessment program and performing the baseline assessment of the pipeline facilities. An effective and comprehensive risk assessment program requires a tremendous quantity of physical data for the pipeline facilities, the input and review of the data in the risk assessment model, and continual updating of both the data and model itself. The annual cost stated in this NPRM of $66,000 per year should be the expected minimum expenditure for each company rather than for the entire pipeline industry. There is no cost estimate presented for the baseline assessment. The intelligent pigging program alone just during the initial assessment program could cost approximately $60 million to $100 million assuming the use of high resolution magnetic flux inspection tools. This cost estimate does not include the expense of verification digs and possible service outages.

GPG agrees that the benefits of this NPRM cannot easily be quantified. Since the NPRM does not address the factors that are responsible for the largest percentage of pipeline incidents – third party damage -- the benefit is likely to be significantly less than it could be, and the cost much greater. GPG believes that a cost benefit analysis would show that increased attention to third party damage provides the greatest opportunity for improvement of safety.

This proposed rulemaking also "provides for a validation process which gives the regulator (OPS) the opportunity to influence the assessment and the interpretation of results". It further states that "having regulators validate the adequacy and implementation of this process, should expedite the operator's rates of remedial action…". This tight control over the process by OPS is counter to the performance-based standard that is espoused in this rulemaking. GPG would heartily agree that this "process of planning, assessment and evaluation will provide operators with better data on which to judge a pipeline's condition" as stated, but takes issue with the capability of the regulator to be a better judge of the process.

It is again stated in this section that OPS cannot quantify the economic benefits for the continual integrity management evaluation portion of this rulemaking but that the "strengthening" of the pipeline system is justification enough. GPG believes there should be a realistic cost benefit analysis in this rulemaking process. Without such an analysis, it appears the pipeline industry is being treated in an arbitrary manner and being placed at a competitive disadvantage to other, competing forms of energy transportation without any cost benefit justification.

The last issue in this section that requires revision is the time estimate for the annual update of integrity management plans. The data collection requirements, data input and evaluation of the results can easily take an order of magnitude more than the 33 hours per plan that is estimated. OPS has again seriously understated the cost impact figures.

Unfunded Mandates

OPS has stated that this rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. GPG agrees that this proposed rule does not result in costs of $100 million or more to state, local or tribal governments. However, GPG believes the OPS cost estimate to the private sector of less than $100 million is not realistic. All of the components of the rulemaking such as the integrity assessment programs by the pipeline operators and the prescribed inspection or testing have been grossly underestimated as to their financial impact. The cost to the pipeline industry of this proposed rule will far exceed $100 million.

National Environmental Policy Act

"Because pipeline failure rates are low, shifting the time at which high consequence areas are assessed forward by a few years, has only a small effect on the likelihood of pipeline failure in these locations. Neither internal inspection nor pressure testing provide protection against all threats to pipeline integrity—specifically they do no prevent outside forms of damage, the most significant contributor to hazardous liquid pipeline failures."

The conclusions of OPS regarding the environmental impact illustrate the difficulty in accepting the necessity for this prescriptive rulemaking in its present form. OPS acknowledges that pipeline failure rates are already low, internal inspections or pressure testing will not provide protection against the most significant threat to pipeline integrity—damage by outside force, and that most of the hazardous liquid pipeline operators are already performing most of the activities proposed by the rule. These conclusions beg the question of why this rulemaking in its prescriptive format is necessary. Since third party damage can occur at any time and may not even be detectable by expensive testing techniques such as smart pigging, OPS should instead address the promulgation of effective damage prevention legislation that is vigorously enforced. Prevention of third party damage is a much more effective use of regulatory and industry resources rather than expensive and ineffective attempts to detect and mitigate the damage after it has occurred.

Rule Language

GPG concurs with comments offered by INGAA on the rule language, and believes it should be modified to be consistent with the comments offered above.

In conclusion, GPG appreciates the opportunity to offer these comments, and hopes they will be considered as part of the ongoing effort and desire to further enhance pipeline safety. As a corresponding rule for natural gas transmission pipelines is developed, GPG urges RSPA to recognize the differences between natural gas and hazardous liquid pipelines and products, and to craft a rule that allows and encourages pipeline operators to choose appropriate methods from all those available to address the identified risks. GPG remains committed to working with INGAA and OPS in this effort.

Sincerely

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